Combining Surface Geochemical Surveys and Downhole Geochemical Logging for Mapping Hydrocarbons in the Utica Shale*

Rick Schrynemeeckers[1]

Search and Discovery Article #41463 (2014)**
Posted October 20, 2014

*Adapted from oral presentation given at AAPG 43rd Eastern Section Meeting, London, Ontario, Canada, September 27-30, 2014
**AAPG©2014 Serial rights given by author. For all other rights contact author directly.

[1]Amplified Geochemical Imaging, LLC, The Woodlands, TX, USA (Schrynemeeckers@AGIsurveys.net)

Abstract

Given the heterogeneity of shale plays, it is important to identify hydrocarbon variability in a 3-dimensional sense. To capture this 3-dimensional hydrocarbon picture both Amplified Geochemical Imaging and Amplified Geochemical Logging were used in the Utica shale play. A surface geochemical survey was used to generate a 2-D hydrocarbon map over the area for both gas and liquid phase hydrocarbons. The surface geochemical survey incorporated a passive sampler containing a specially engineered hydrophobic adsorbent encased in a layer of microporous expanded polytetrafluoroethylene (ePTFE) and monitored hydrocarbons from C_2 to C_{20}. The resulting data was used to:

• identify three distinct gas hydrocarbon signatures
• identify a liquid hydrocarbon signature across the field
• differentiate between economic and noneconomic gas areas in the play
• differentiate and map light and heavy hydrocarbon signatures throughout the area
• image hydrocarbon anomalies aligned with surface lineaments indicating hydrocarbon filled fractures.

In addition to the surface geochemical survey, Downhole Geochemical Logging was also employed on a well drilled after the surface survey. Downhole Geochemical Logging of the cutting samples provided the ability to directly characterize the composition of hydrocarbons vertically through the prospect section. The methodology measured a broad compound range from C_2 to C_{20} and had a 1,000 times greater sensitivity than traditional methods. As a result, the data was used to:

- detect by-passed pays
- infer compartmentalization
- infer from which zones the economic and noneconomic gases in the play may have originated
- infer from which depths and formations the liquid hydrocarbons may have originated.

The combination of the surface survey and the Downhole Geochemical Logging provided a 3-D picture of the hydrocarbons in this play. As such, the data indicated that the ubiquitous noneconomic gas might have been coming from the Utica formation. The survey also allowed the mapping of areas where the economic gas could be found and implied that the economic gas had a unique source and was in fact originating from the deeper Trenton formation and accumulating in natural fractures above. Additional the Downhole Geochemical Logging inferred that the liquid hydrocarbon locations mapped by the surface survey were most likely coming from the Upper and Lower Queenston formation and that there was mostly likely a seal between the two sections.

AAPG Eastern Section 42nd Annual Meeting

Combining Surface Geochemical Surveys and Downhole Geochemical Logging for Mapping Hydrocarbons in the Utica Shale

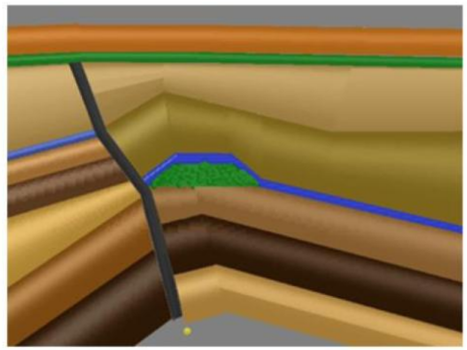
By Rick Schrynemeeckers

©2014 Amplified Geochemical Imaging LLC

AMPLIFIED GEOCHEMICAL IMAGING, LLC

The Science Behind the Technology

Vertical Migration



Microseepage signal affected by:

- **Pressure (P)**
- **Porosity (θ)**
- **Net Pay (h)**

Macroseepage:
- Detectable in visible amounts
- Pathway follows discontinuities
- Offset from source/reservoir

VS

Microseepage:
- Detectable in analytical amounts
- Pathway is nearly vertical
- Overlie source/reservoir

AMPLIFIED GEOCHEMICAL IMAGING, LLC

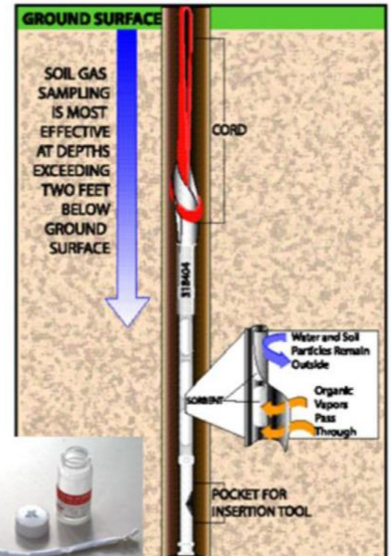
Presenter's notes: In this diagram, the green section in the middle of the slide represents the reservoir and the horizontal blue line on top of it represents the seal. The thick gray vertical line next to the reservoir represents a fault. We are all familiar with macro seepage. Hydrocarbons from macroseepage travel along faults, find their way to the surface, and can be visually seen. Their concentrations are at percent levels and they are normally visual. Additionally, *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

their location at the surface is normally offset from the source. What most of us are less familiar with is microseepage. Microseepage occurs when hydrocarbon molecules in the reservoir go into the gas phase. These gas molecules are lifted-up by microbuoyancy from the pressure in the reservoir. These small gas molecules move upward, essentially vertically, along grain boundaries through the seal and through the lithology above the reservoir to the surface. Therefore, macroseepage occurs at percent levels and microseepage occurs at part per billion levels. Macroseepage travels along faults to get to the surface and microseepage moves upward due to microbuoyancy from reservoir pressure. The location of macroseepage hydrocarbons at the surface is offset from the source while hydrocarbons from microseepage are essentially directly above the source.

Modules

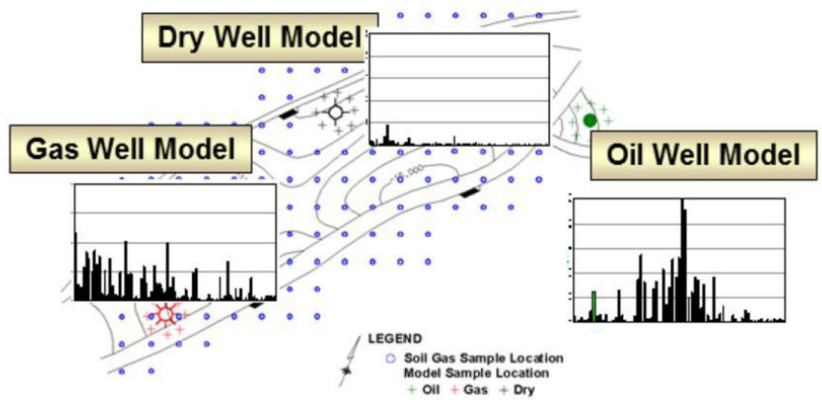
- Patented, passive, sorbent-based
  - Chemically-inert, waterproof, vapor permeable
  - Direct detection of organic compounds
  - Sample integrity protected
- Engineered sorbents
  - Consistent sampling medium
  - Minimal water vapor uptake
- Time-integrated sampling
  - Minimize near-surface variability
  - Maximize sensitivity (up to C20)
  - Avoids variables inherent in instantaneous sampling
- Duplicate samples



Presenter's notes: Amplified Geochemical Imaging Technology was developed. This new technology uses passive adsorbent sampling. The passive sampler contains a specially engineered hydrophobic adsorbent encased in a layer of microporous expanded polytetrafluoroethylene (ePTFE). This module is placed in the ground about 1.5-2.0 ft down in a small hole and then covered. It remains in the ground for approximately three weeks. This 3-week period is important because it allows a sufficient volume of hydrocarbons to migrate to the surface and adsorb onto the module.

Surveys Design

Model development..



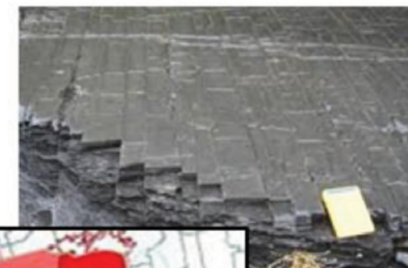
Presenter's notes: Deployment plans differ based on the project objective (i.e. frontier areas, prospect ranking, acreage relinquishment, field development, or phase identification for unconventional plays). The most common scenario is a grid pattern over the area of interest. The blue circles represent the location of each module. The spacing between the modules can range from 250 m to 2 km depending on the size of the field and the project objectives. *(Presenter's notes continued on next slide)*

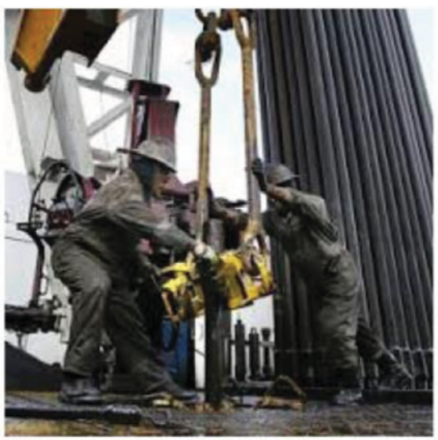
(Presenter's notes continued from previous slide)

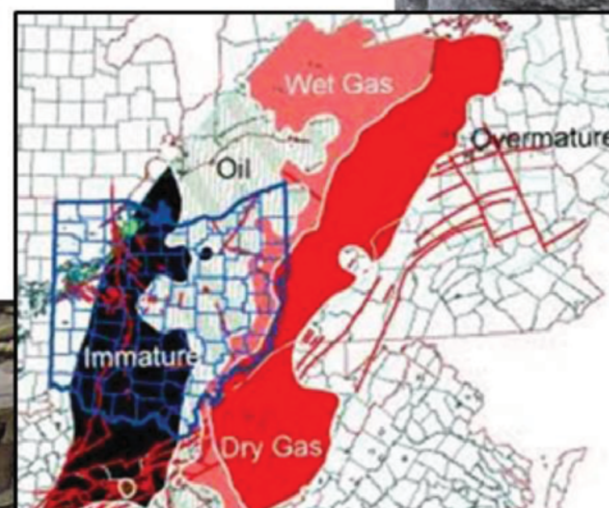
Note the crosses around the dry well, gas well, and the oil well. Normally 15 modules are placed around such calibration wells. Calibration wells are used as hydrocarbon signal end-members for comparison during the evaluation and statistical analysis of the data. So, for example, if an oil signature is detected in the survey, that oil signature can be compared against the oil calibration signature. Note that there are distinct differences between the dry well, gas well and oil well signatures. This ability is unique to Amplified Geochemical Imaging technology because this is the only surface geochemical technology that can measure the full range out to C_{20}, thus providing a clear hydrocarbon signature – not just compound ratios.

The Utica Shale Play
Case Study

Investigating fracture porosity

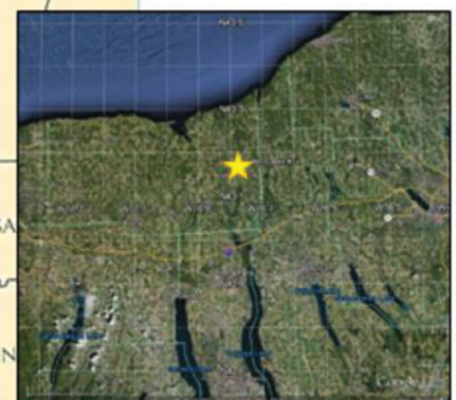






AMPLIFIED GEOCHEMICAL IMAGING, LLC

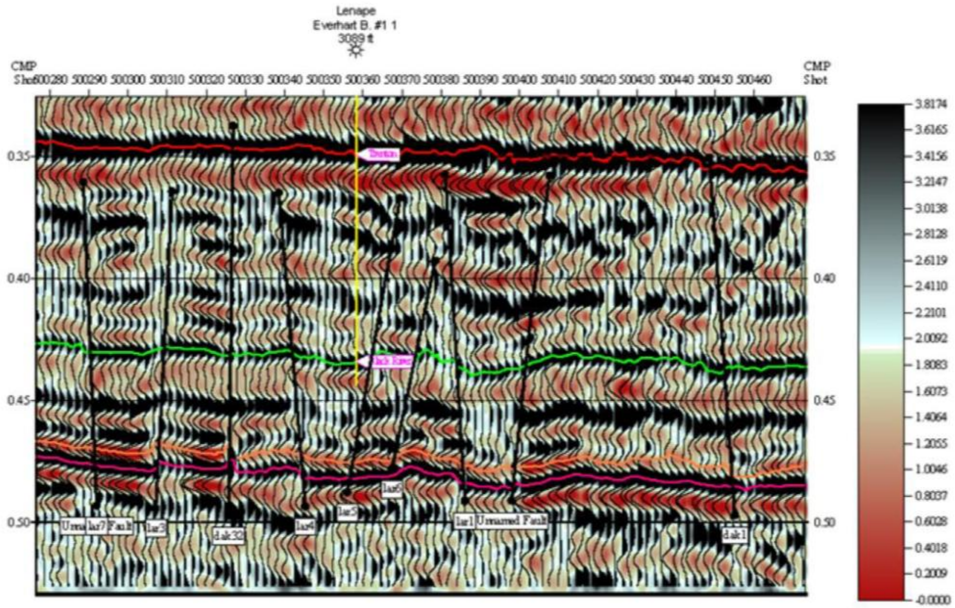
Geochemical Survey – Wayne County NY



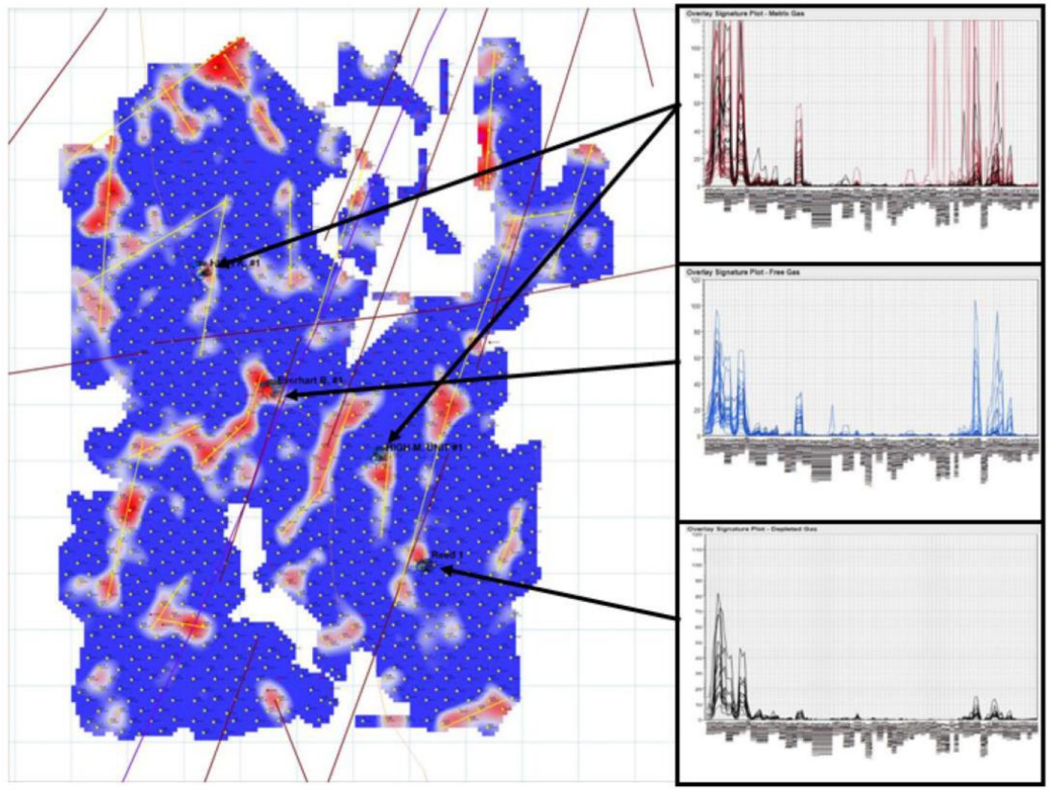
2005 Geochemical survey area

AMPLIFIED GEOCHEMICAL IMAGING, LLC

Everhart #1 Well



Presenter's notes:Three wells were drilled prior to the Everhart well and each well was noneconomic. This shows basement propagating faults with the Everhart well. The Everhart well was completed in the Trenton formation and was a highly successful well. The IP was approximately 10 mm and then leveled off to 3 mm. This well was used for calibration purposes during the survey because of its high production.

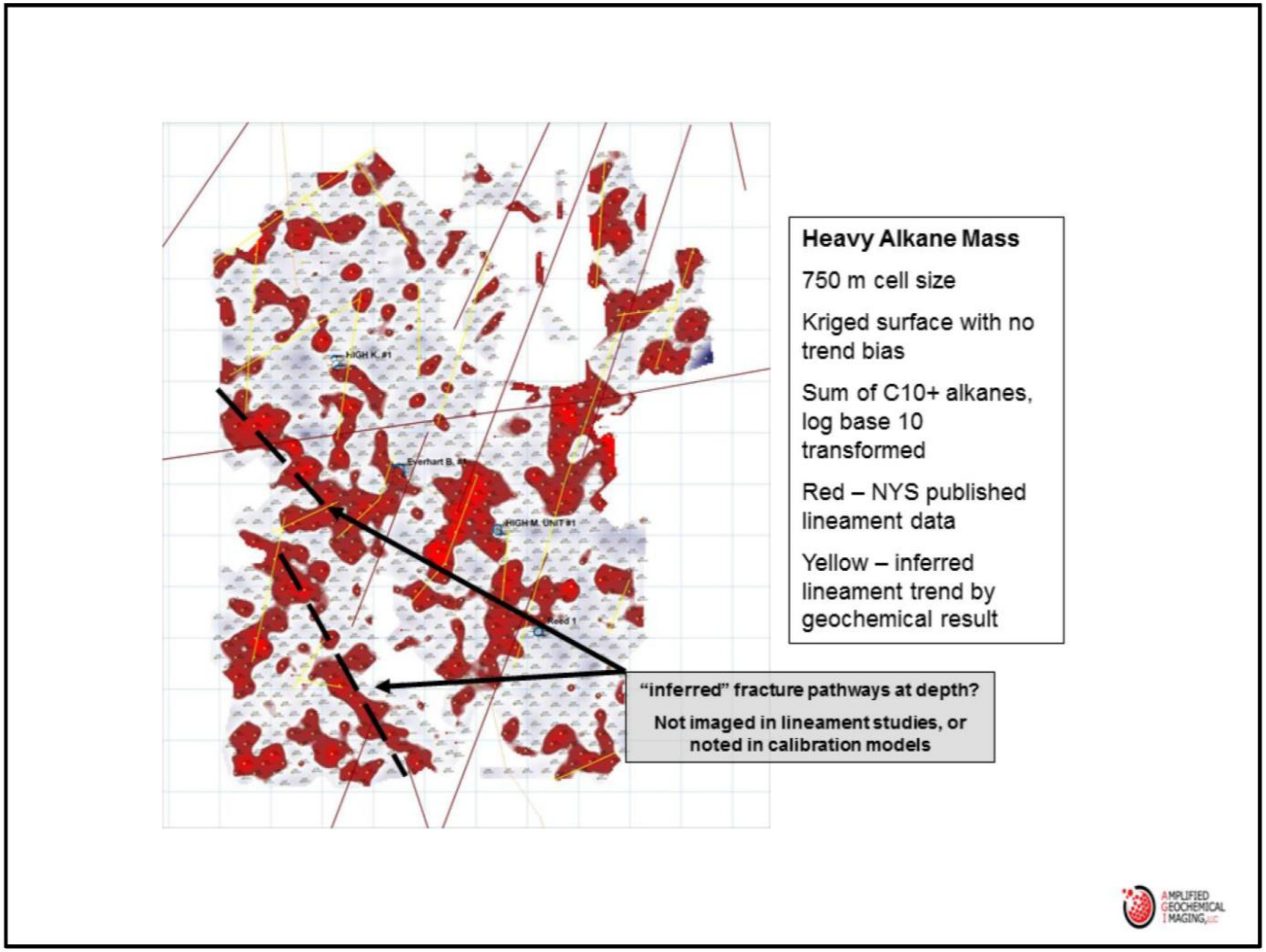


AMPLIFIED GEOCHEMICAL IMAGING, LLC

Presenter's notes: The right side of the slide shows three chromatograms. The red chromatogram at the right top is an overlay of all the chromatograms from the samples taken around the M High and K High wells. The blue chromatograms are an over lay of all the samples taken around the Everhart well. What is striking is that the M High and K High well fingerprints look very similar to the Everhart fingerprint. However, the statistical integration of the data can *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

clearly distinguish subtle differences that are not apparent to the naked eye. Notice the K High well is right on the edge of a small positive anomaly. After the initial drilling of this well, pressure began to increase. It is believed that this may be due to leakage from the gas-filled fracture near the well that flowed into the well. The black chromatograms indicate a compilation of the samples around the Reed 1 well that was also noneconomic. These three-gas hydrocarbon signatures were differentiated my Hierarchical Cluster analysis. This demonstrates that while there seems to be gas across the entire area, the Amplified Geochemical Imaging can differentiate between the gas signatures in the Everhart well, which is very profitable, from the other two gas signals (M High and Reed 1) which are not profitable. The client believed that the red anomalies indicated by the Everhart were actually natural fractures that were filled with Everhart gas from the deeper Trenton formation. Note that the general trend of the red anomalies align very nicely with surface lineaments.



Presenter's notes: This map shows heavier HC intensity maps. These heavier hydrocarbons did not show up on the precious Everhart model map b/c the previous map was mapping anomalies based on similarity to the Everhart gas signature. This heavier hydrocarbon map may indicate there are heavier hydrocarbons present as well. At the time of this survey, oil had not been discovered this far north in the Utica and the client's focus was simply gas. However, since that time ENERVEST has had oil discoveries in this northern Utica field.

Downhole Geochemical Logging Analysis

- Cuttings are collected in glass jars, directly from the shaker table during drilling
- Mud blanks are also collected as well
- Analyses normally done in 2 weeks

1,000 time more sensitive than traditional methods

Focuses on hydrocarbon fluids in various zones

- Measures from the C_2 to C_{20} carbon range
- Easily differentiates between multiple phases
- Identifies reservoir compartmentalization
- Identify by-passed pays

Does this work with all drilling muds?

> ***No – Not with ALL Oil-based muds***

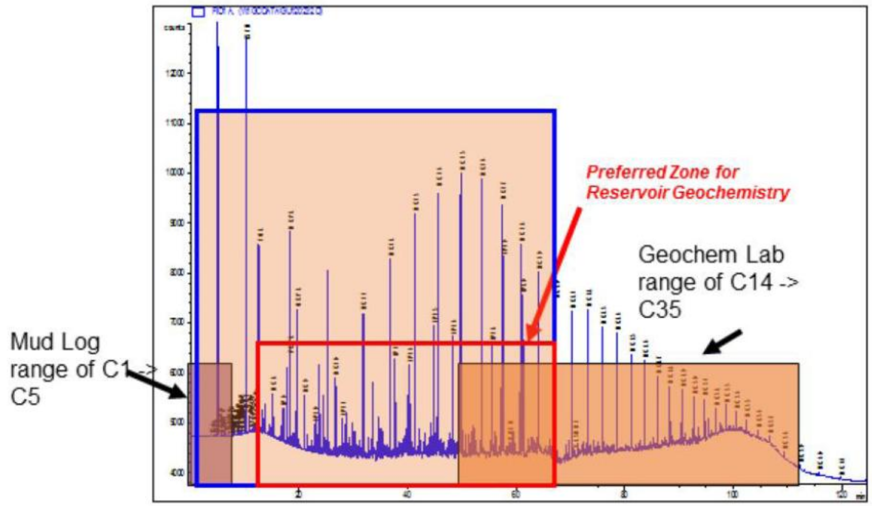
AMPLIFIED GEOCHEMICAL IMAGING, LLC

Presenter's notes: One of the most common tools used to understand reservoirs is conventional core analysis. Scientists look at various rock properties like porosity, permeability, variability across a core, grain density, and fluid saturation to better understand how fluids (i.e. oil) will flow through and from a reservoir. This is important in attempting to predict well and field productivity. Additionally, core analysis normally takes many months b/c of the *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

backlog of samples in the various labs. DGL can provide you data in just a few weeks, not a few months. In addition, how do you know where to take your cores? The Expl VP at SWM recently said at an AAPG symposium in Vancouver that he prefers to wait a little while into the project to determine where is the most strategic area of the field to take cores, because when little is known they can spent a lot of money taking and analyzing cores from the wrong part of the field. However, while all of these are important properties to measure they do not really focus on hydrocarbons. They focus on rock properties to predict how hydrocarbons will flow from the well bore.

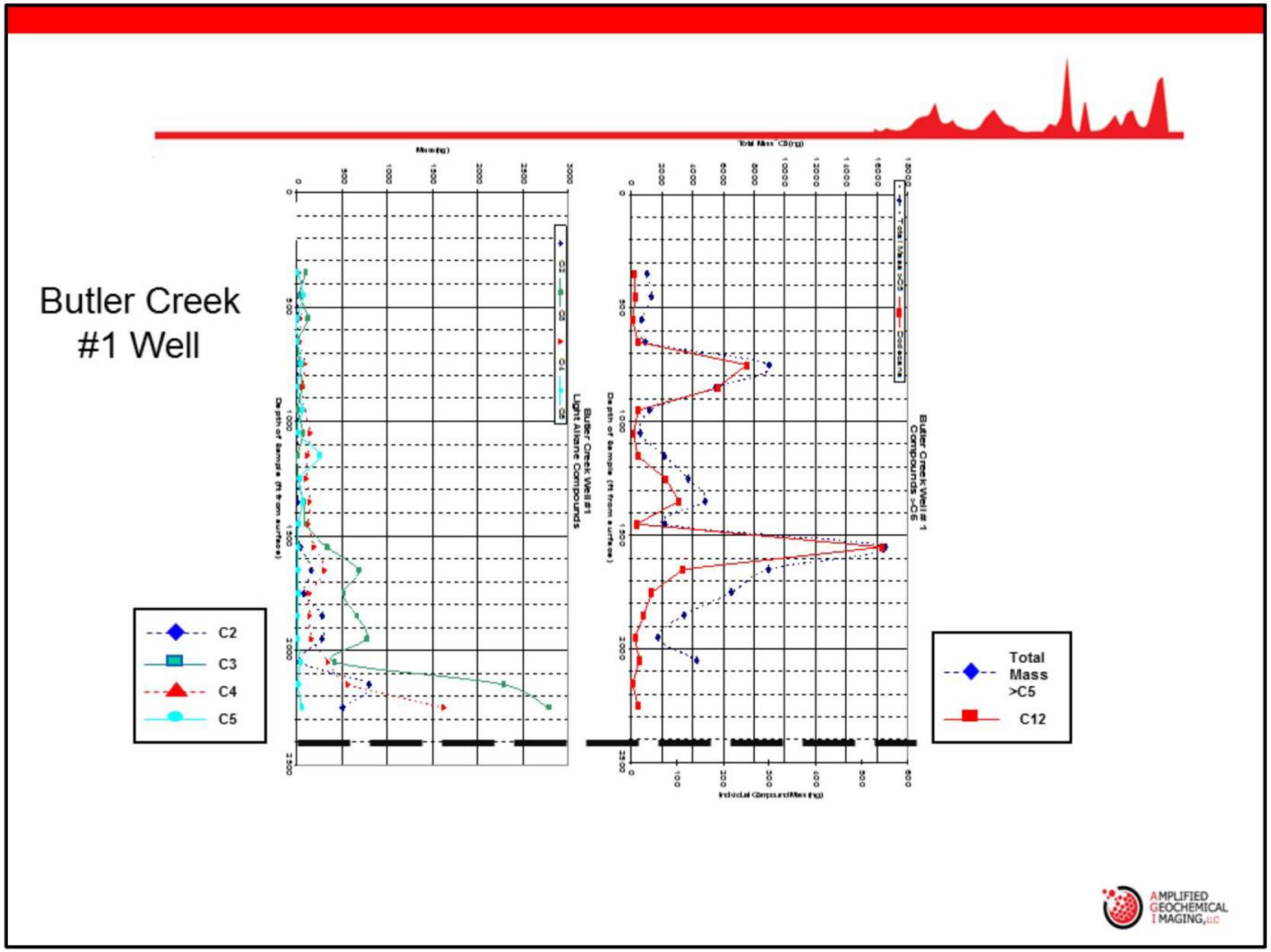
Conventional Hydrocarbon Analyses



Presenter's notes: This shaded blue box shows the coverage range for DGL. Just looking at the box shows the density of compounds covered by the method. DGL technology measures from C_2 -> C_{20}, which enables the data to provide HC fingerprints for gas, condensates, and oils. Notice I did not say that DGL estimates or guesses at the HC phase as other methods do. DGL provides the ability to not only differentiate between gas, condensates, and oils, *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

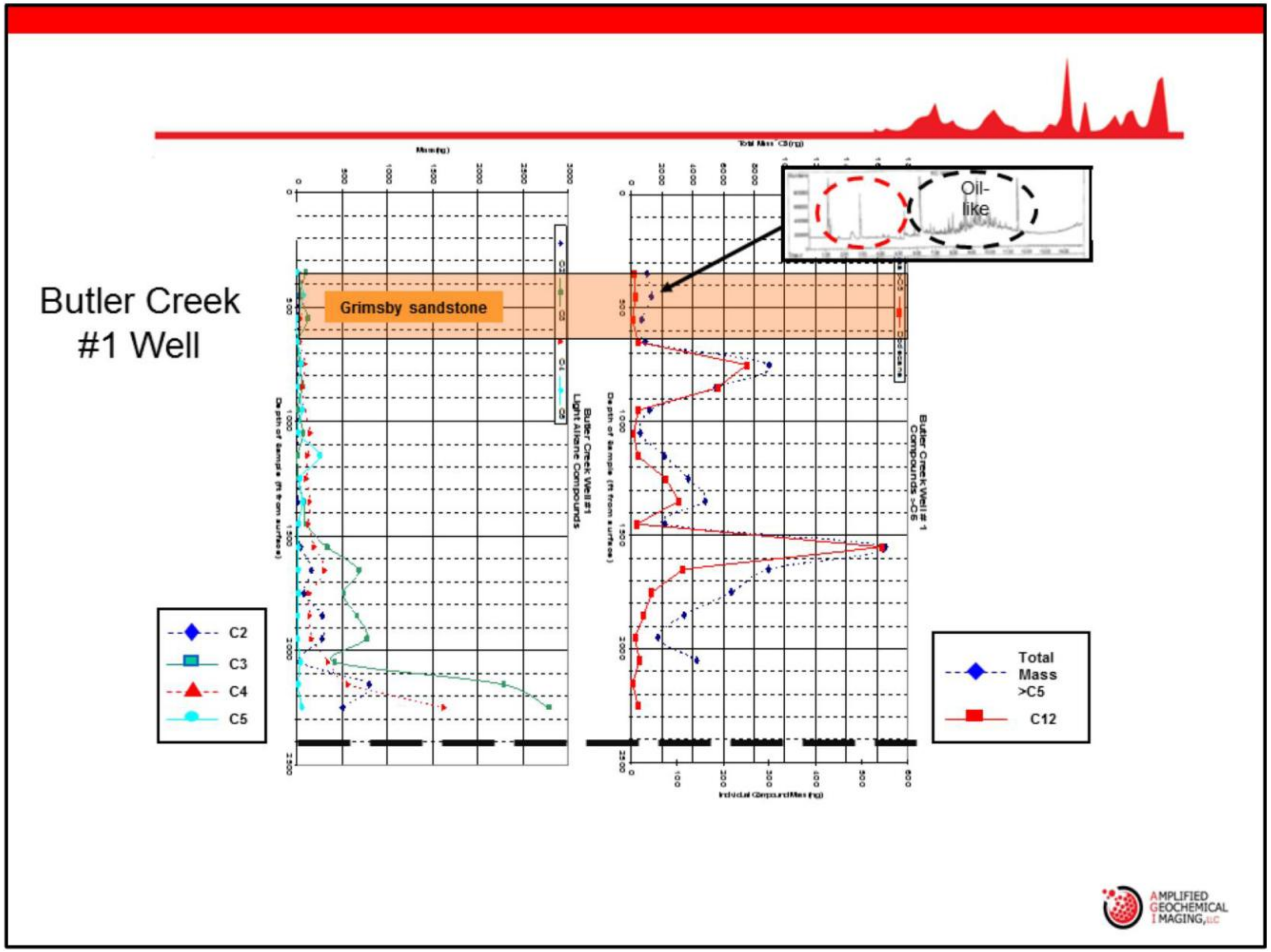
but it allows you to also differentiate between several different oil signatures, which is not possible with other technologies. In addition, DGL measures down to the PPB range that is a 1,000 times lower than other technologies. This allows the method to measure seals down to the molecular level, which no other method can do. Finally, and probably most importantly, since the AGI method measures many of the Isoprenoids between C_{10} and C_{20}. This technology provides the ability to assess compartmentalization in the way reservoir geochemists do. While reservoir geochemists look at the entire HC to understand the HC phase (i.e. gas, condensate, or oil), assess alterations effects, and assess similarity between various HC fingerprints, they primarily work with the C_{10} to C_{22} range for evaluating compartmentalization for several reasons.



Presenter's notes: Note the DGL profile exhibits numerous HC responses, some of them quite significant, which were not detected at ALL on the mudlogs. Again, the green arrows indicate depths of oil-like response and the red arrow indicates a depth with gas-like response. You can also see the gas components, C_2 -> C_5 on the left scale and the oil components C_{12} on the right scale. Immediately several things jump out at you. First of all the client was targeting *(Presenter's notes continued on next slide)*

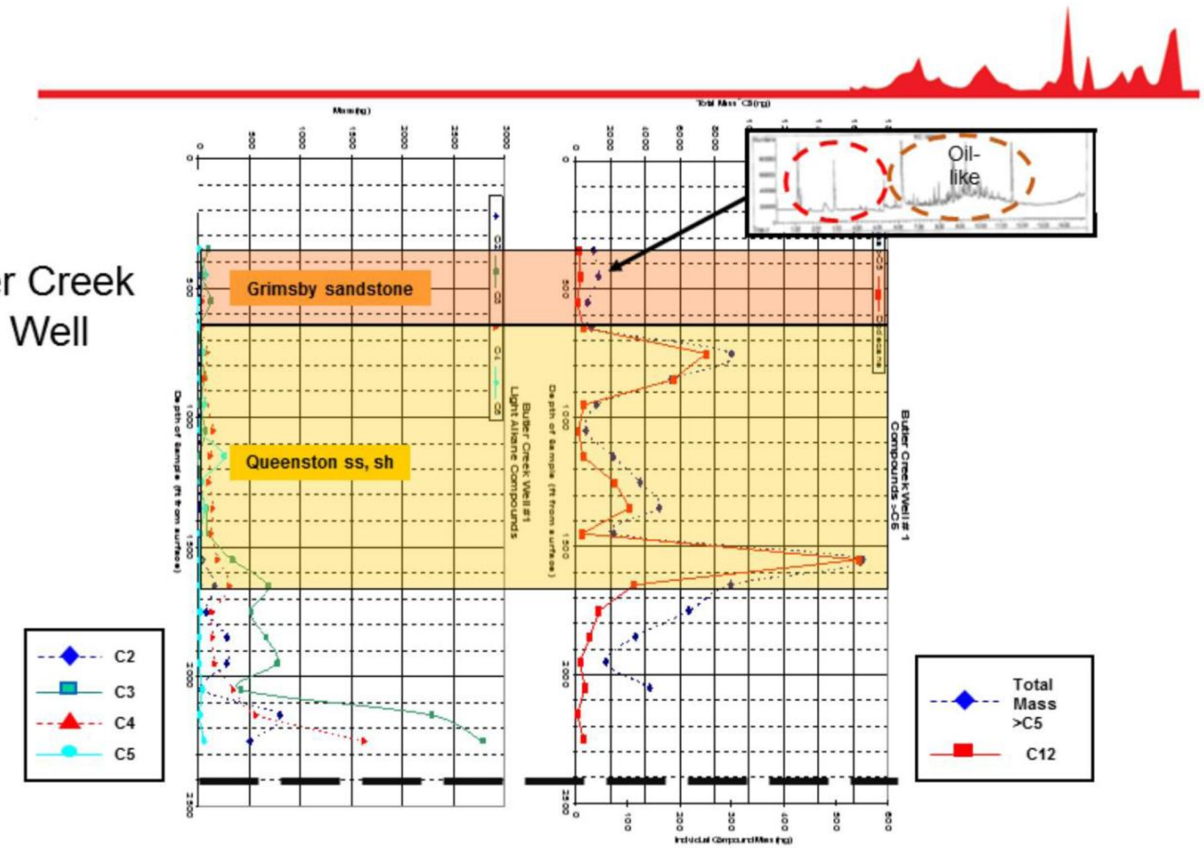
(Presenter's notes continued from previous slide)

a specific gas reservoir at 2,500 ft. Notice the gas scale increases sharply at about 2,100 ft. This begs the question is a seal leak occurring or is the reservoir actually at 2,100 ft instead of 2,500 ft. Additionally you notice the oil log on the right indicates no increase of heavy HC just above the deep reservoir which gives credence to the fact that this must be a gas reservoir. There are two known shale oil reservoirs above the target reservoir. These can be seen at 750 ft and 1,550 ft. There appears to be some slight background increase at about 400 ft and something more significant at 1,350 ft. Remember, the client was not even aware at the time of this Downhole project that oil was a possibility in this well. However, much more information can be garnered from this data when it is combined with other G&G data, particularly the stratigraphic data.



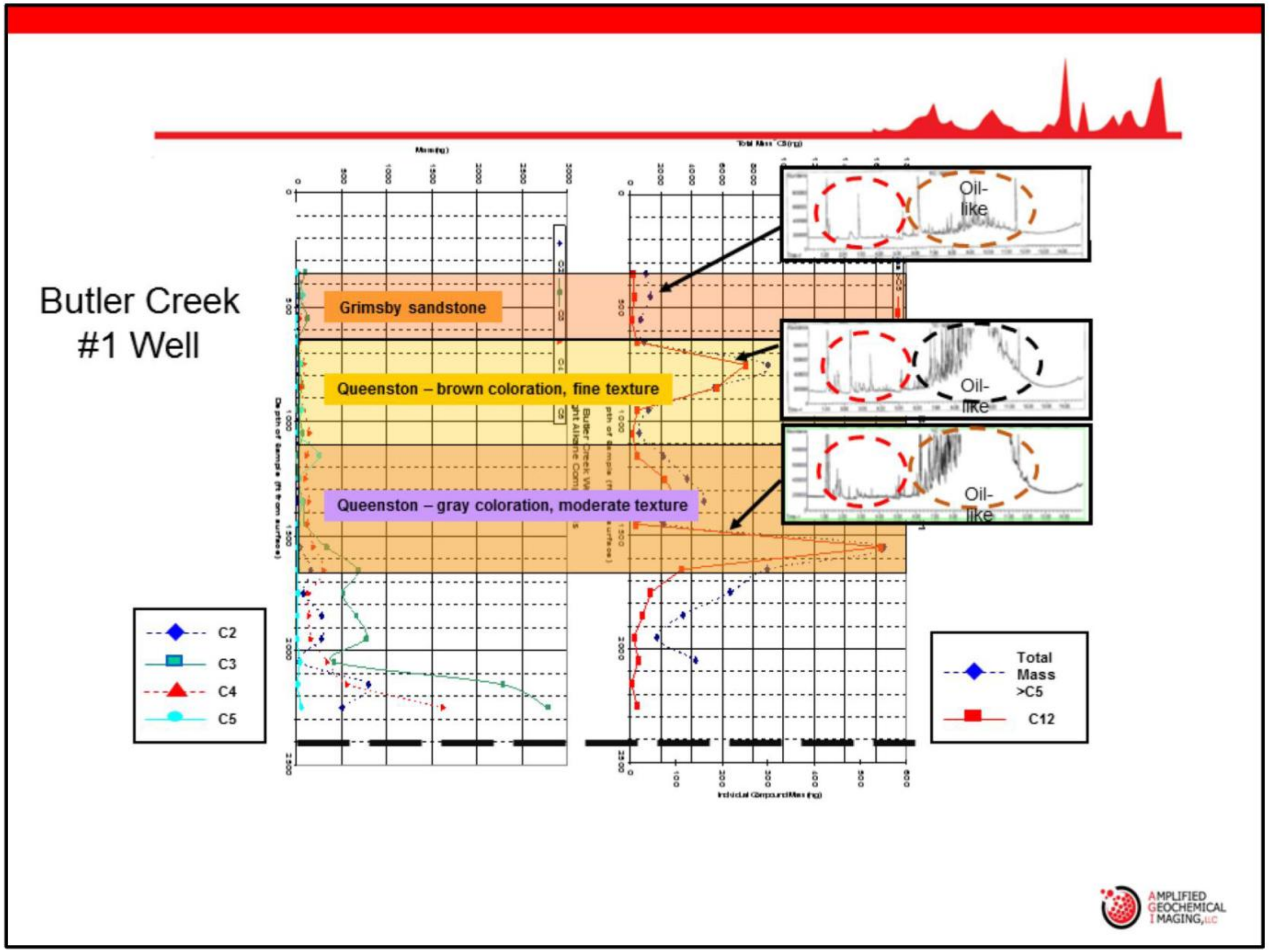
Presenter’s notes: The section from 350-550 ft is Lower Silurian. You see a HC fingerprint at 400 ft shows a definite oil fingerprint. The fact that the HC fingerprint comes back down to baseline at about 600 ft is interesting as that is the transition to another stratigraphic section. This may be indicative of a possible seal, but it is impossible to tell since samples were only collected every 100 ft. If we had it to do all over, we would have had much closer spacing. Given the extreme sensitivity of our method, it is unlikely that this HC show would show up on a well log. Therefore, you have to ask if this is indicative of a missed pay or a possible migration pathway.

Butler Creek #1 Well



AMPLIFIED GEOCHEMICAL IMAGING, LLC

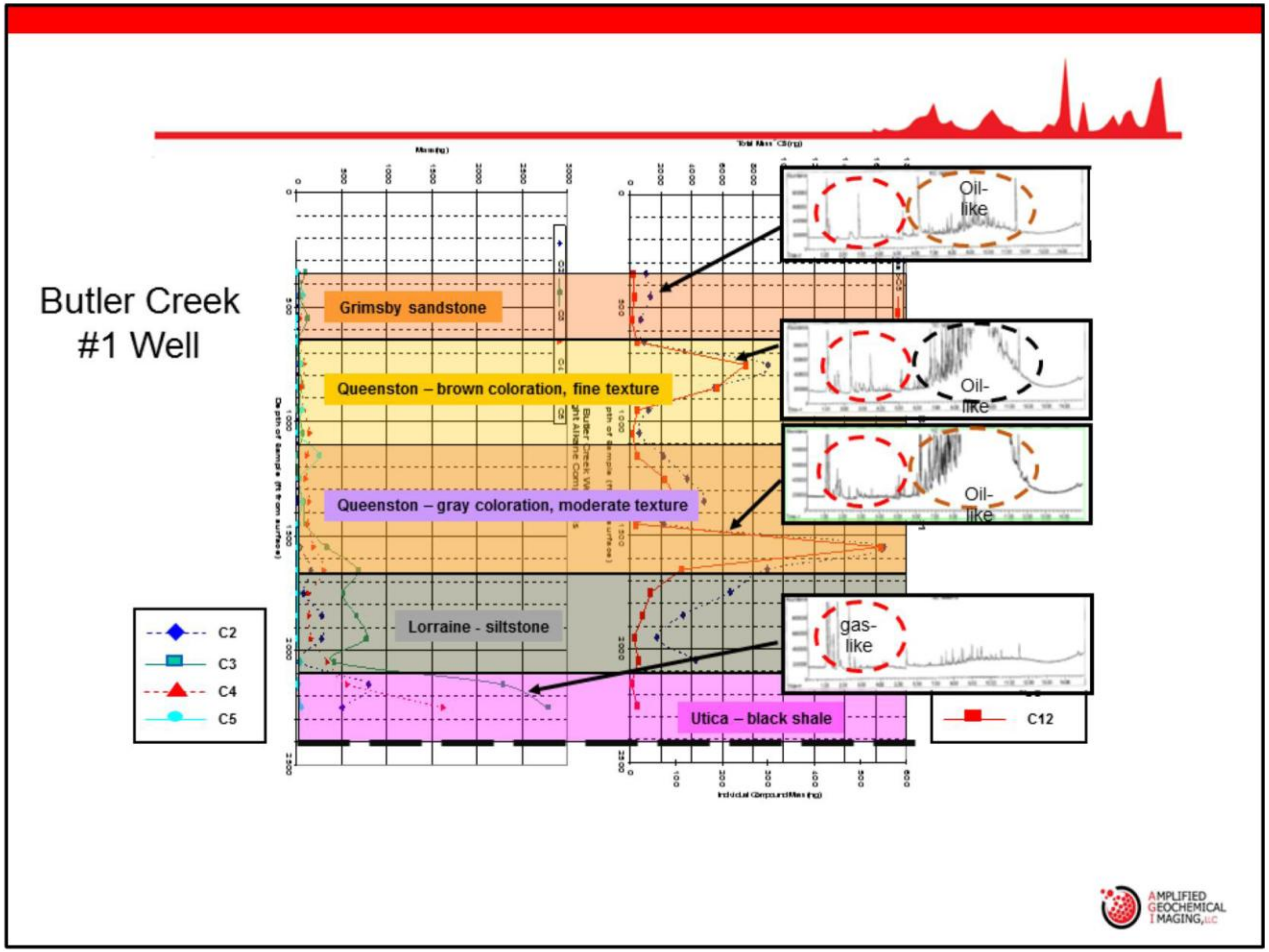
Presenter's notes: The next section is the Queenston and is a very huge section of about a 1,000 ft. The various Strat columns talk about the Queenston as both a sand and a shale indicating the lithology probably varies from clays to sands. The cutting descriptions tend to support that and actually divide this section into an upper and lower section as seen in the next slide.



Presenter's notes: When you combine the G&G data and the DGI (Downhole Geochemical Imaging) data, you begin to get a clearer picture of what might be occurring. From the stratigraphy and lithology, you appear to have three distinct zones. The DGI data corroborates that. First of all the DGI data shows you have oil in all three zones, which is important. Additionally, even though the later eluting HC are off scale you can see differences in the early *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

eluting HCs when you compare all three oils. That is information you probably would not get in a well log. Well logs would probably miss the oil in the L. Silurian section and it would definitely not tell you that you have three different oils. The fact that these three oils are different may indicate potential seals between these sections. We cannot tell that for sure because of the wide 100 ft sampling intervals used for this project. Additionally, remember it was noted in the surface survey that on the compound plots of the heavier (i.e. oil) components we saw a distribution at the surface for the delineation of liquids. This downhole section indicates those oil expressions at the surface were most likely coming from either the upper or lower Queenston formations. Keep in mind not all hydrocarbons are created equal. For example, in the Bakken, oil is produced from both the Bakken Formation and the Three Forks Formation, but the Bakken has better economics, and is the preferred zone for completion, because it has better oil quality and better pressure. Therefore, downhole testing could be used in situations like the Bakken where you may wish to complete a specific zone, but you might have questions about which formation you are in. The AGI downhole could tell you which formation you are in because of the differences in the oil chemistries. Additionally, the oil chemistry can be used to aid in the identification of stratigraphic intervals in areas where you may not have good well control or where the stratigraphy is uncertain. The chemistry of the hydrocarbon found in the cuttings could identify the stratigraphic interval if you have tested similar intervals in other wells in the field.

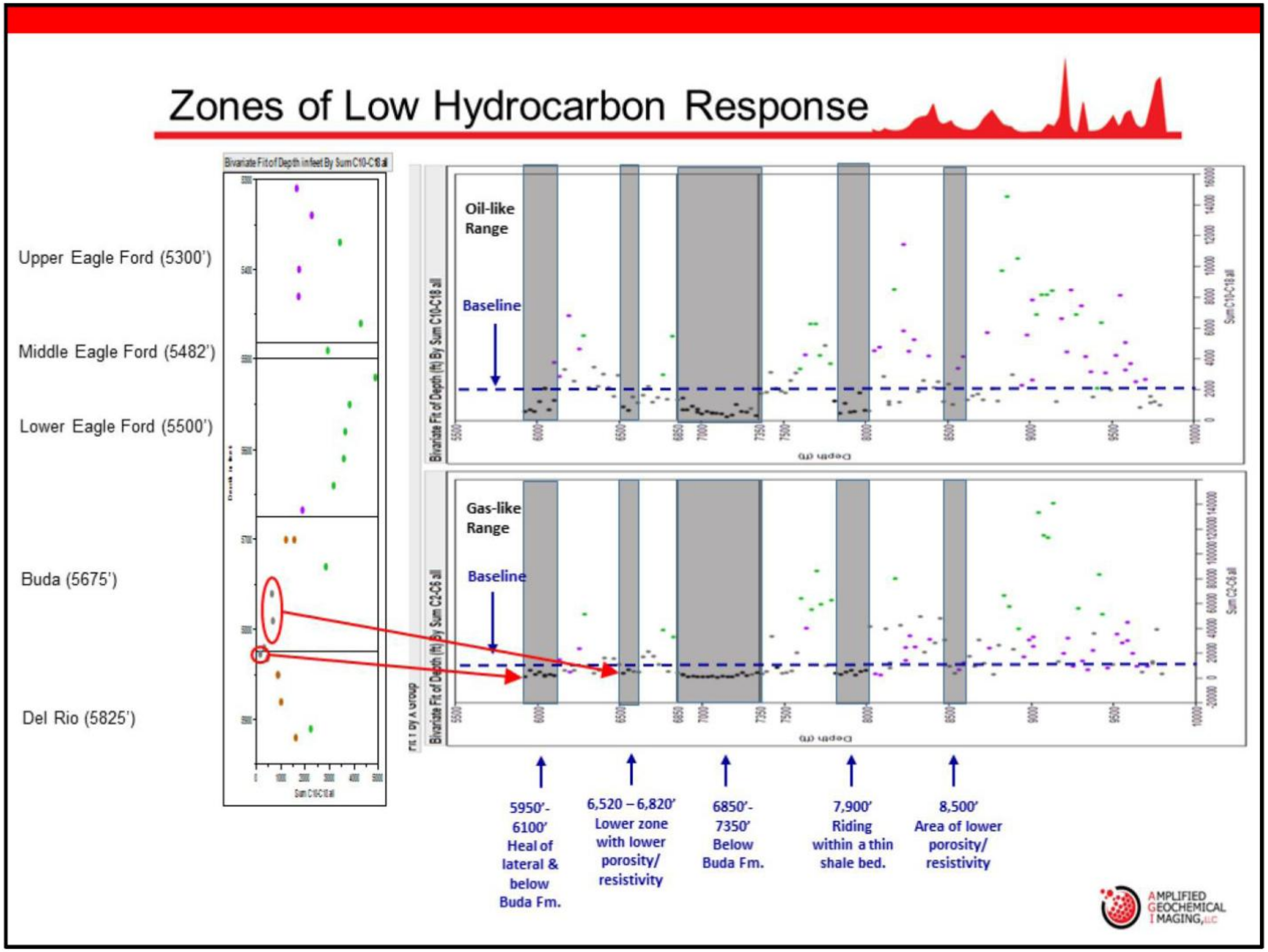


Presenter's notes: The Lorraine Formation is from 1,750 ft to 2,050 ft and below that, you have the Utica Formation. You can see the oil component on the right side of the geochemical log significantly decreasing in the Lorraine Formation to where you almost have a condensate-like HC. By the time you get to the Utica, a gas HC signature is clearly seen. We originally thought we might have a leaking seal or the target Trenton Formation may not have been at 2400 ft, but rather 2,100 ft. What actually may be occurring here is that as you are going deeper you may be cooking the source so that by the time you get to the Utica you are seeing remnant gas from an over-mature source. Therefore, G&G data may be combined with the DGI data giving you a better understanding of what may be occurring in the subsurface.

Downhole Geochemical Logging in the Lateral Eagle Ford Well

AMPLIFIED GEOCHEMICAL IMAGING, LLC

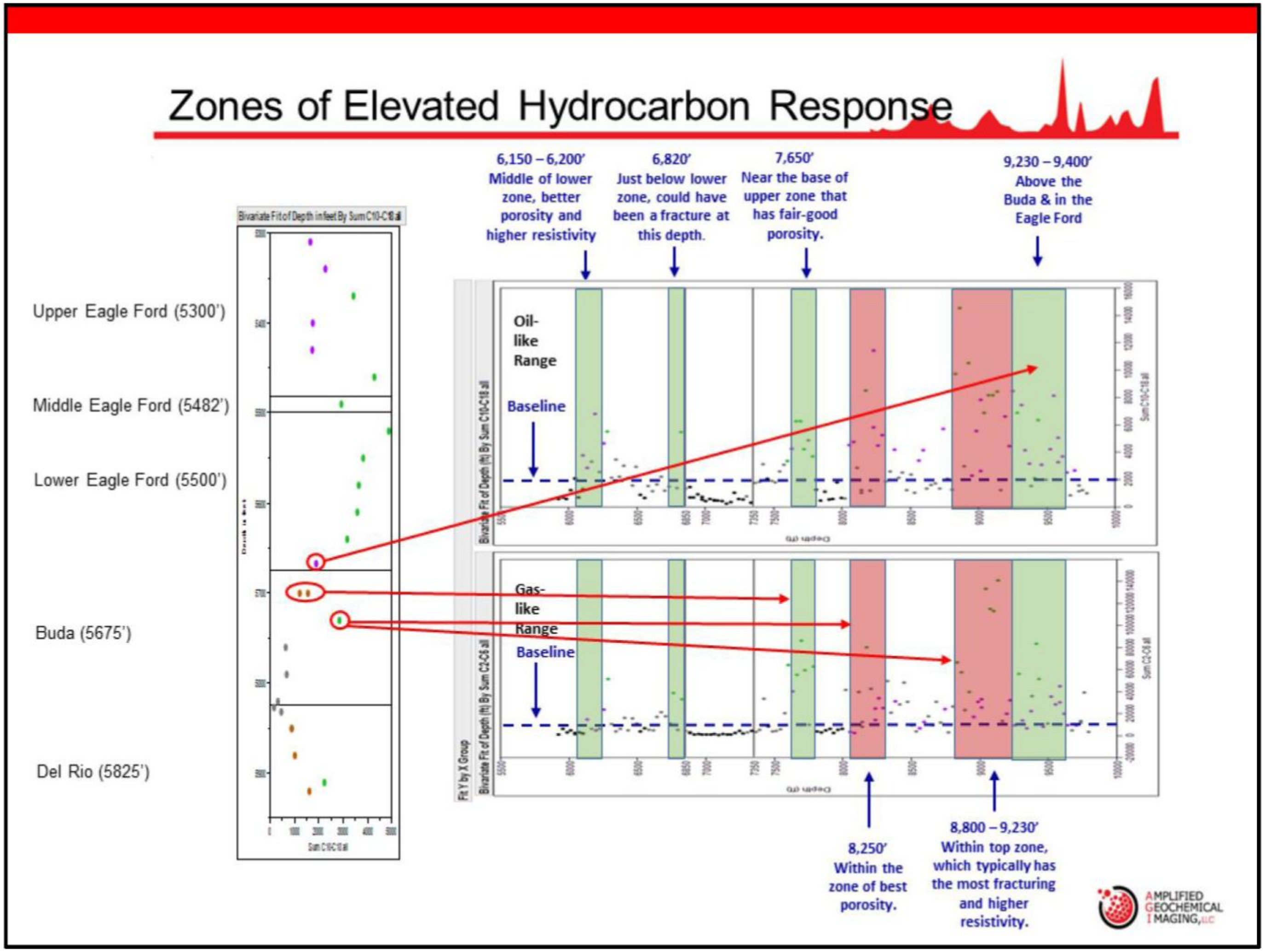
Presenter's notes: 3-D hydrocarbon detection contains a horizontal component and a vertical component. I will start with a brief overview of the horizontal component.



Presenter's notes: The Buda was subdivided into eight different zones based on porosity and resistivity.
Three zones appeared to have higher porosity, resistivity, and perhaps more fractures. Oil-like components are plotted on the top scale while gas-like components on the lower scale. The X-axis on each plot is the depth and the Y-axis is the HC intensity. The depth chart has been turned on its side to more easily represent a lateral vies of the data. *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

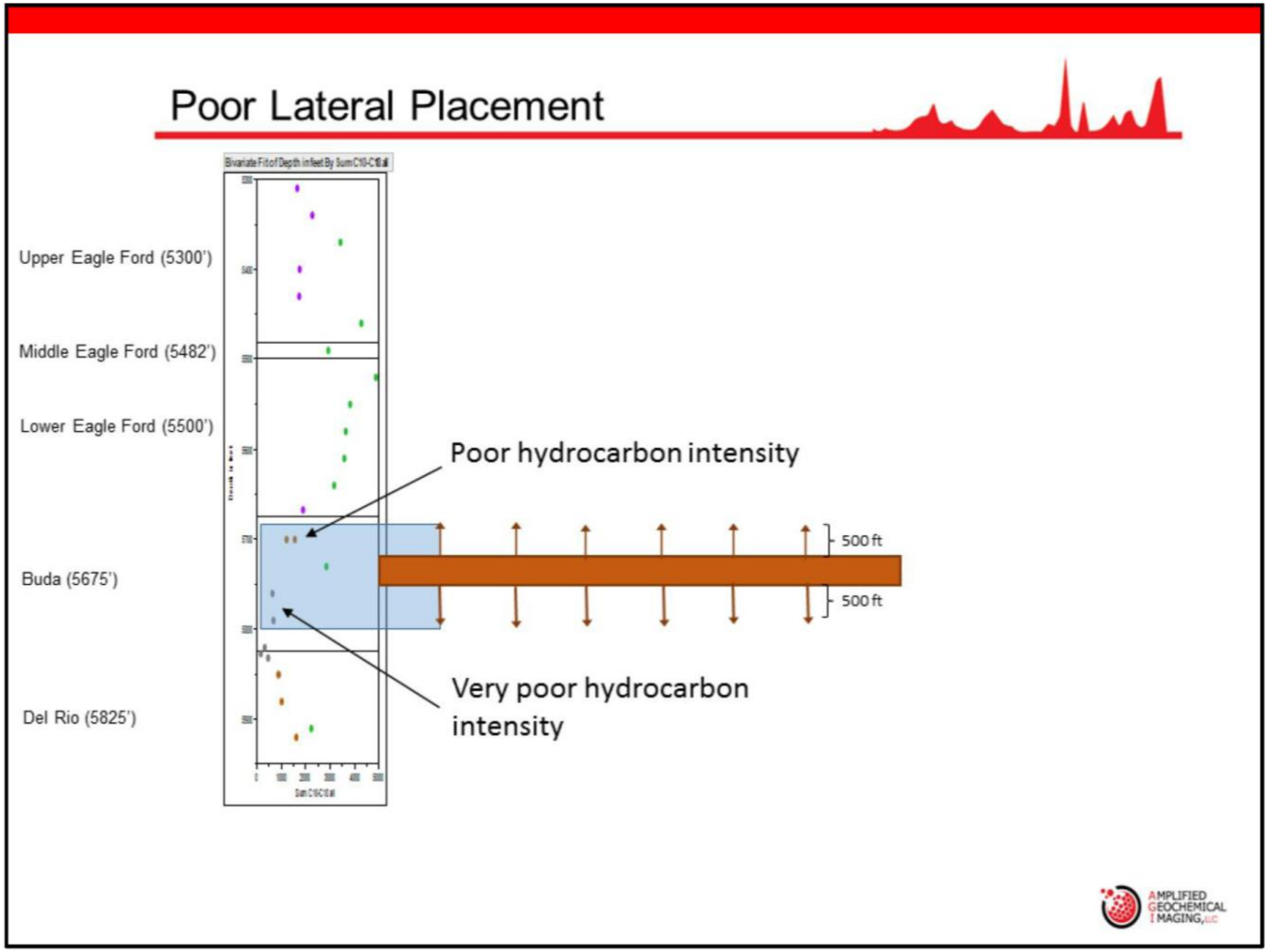
The color of the dots or data points relates to cluster analysis, which will we will not go into except to say the green cluster appears to have the highest degree of intensity and the black has the lowest degree of intensity. We have also added dashed blue line to indicate the approximate HC baseline. The gray shaded areas indicate areas of low HC response according to the DGL data. Conversations with the client indicate correlations between these low DGL readings and well notes. For example, the low DGL concentration from 5,950'-6,100' related to the heel of the lateral drilling where the drill bit was below the intended Buda fm. The downturn in HC concentration from 6,520'-6,820' corresponded to a zone of lower porosity/resistivity. Well logs indicate the decrease in HC concentration from 6,850'-7,350' was due to drilling out of zone beneath the Buda fm. The decrease in HCs at 7,900' was likely due to riding in a thin shale bed. Around 8,500' the lateral drilling was above the upper target zone within the Buda, which was identified as an area with lower porosity/resistivity, which would explain the decrease in there. Therefore, in each case where there is a significant decrease in HC concentration in the lateral drilling event, the DGL detects that decrease and it relates to geologic anomalies on the formation.



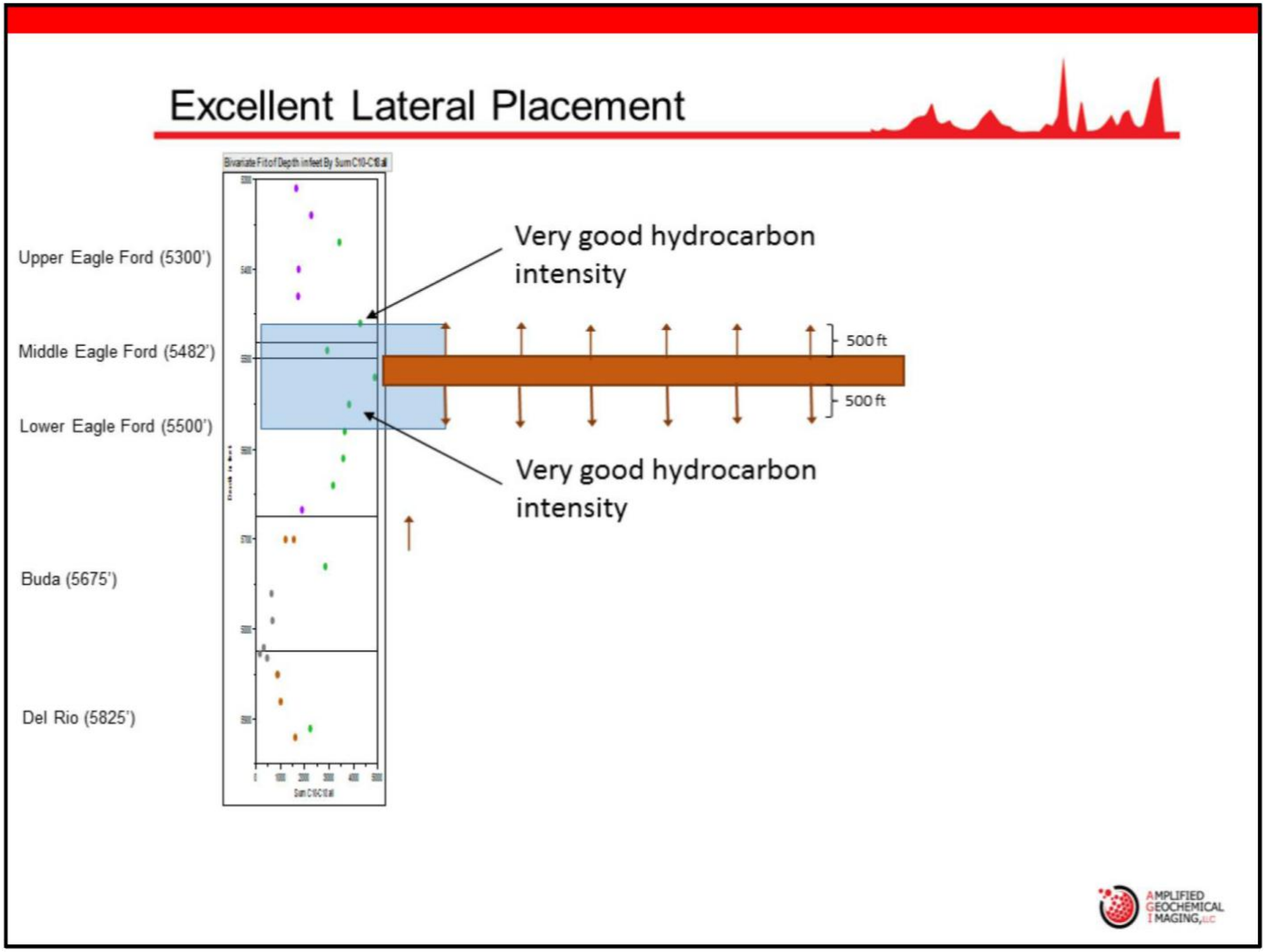
Presenter's notes: As mentioned previously, there were three subdivisions within the Buda that had been identified as zones of higher porosity, resistivity, and perhaps more fractures. These three zones were middle of the lower zone, the base of the upper zone, and the top zone. As seen in the plot above, the increases in HC concentrations from the DGL plot tracked well with these known zones of enhancement. For example, a kick in the oil components is *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

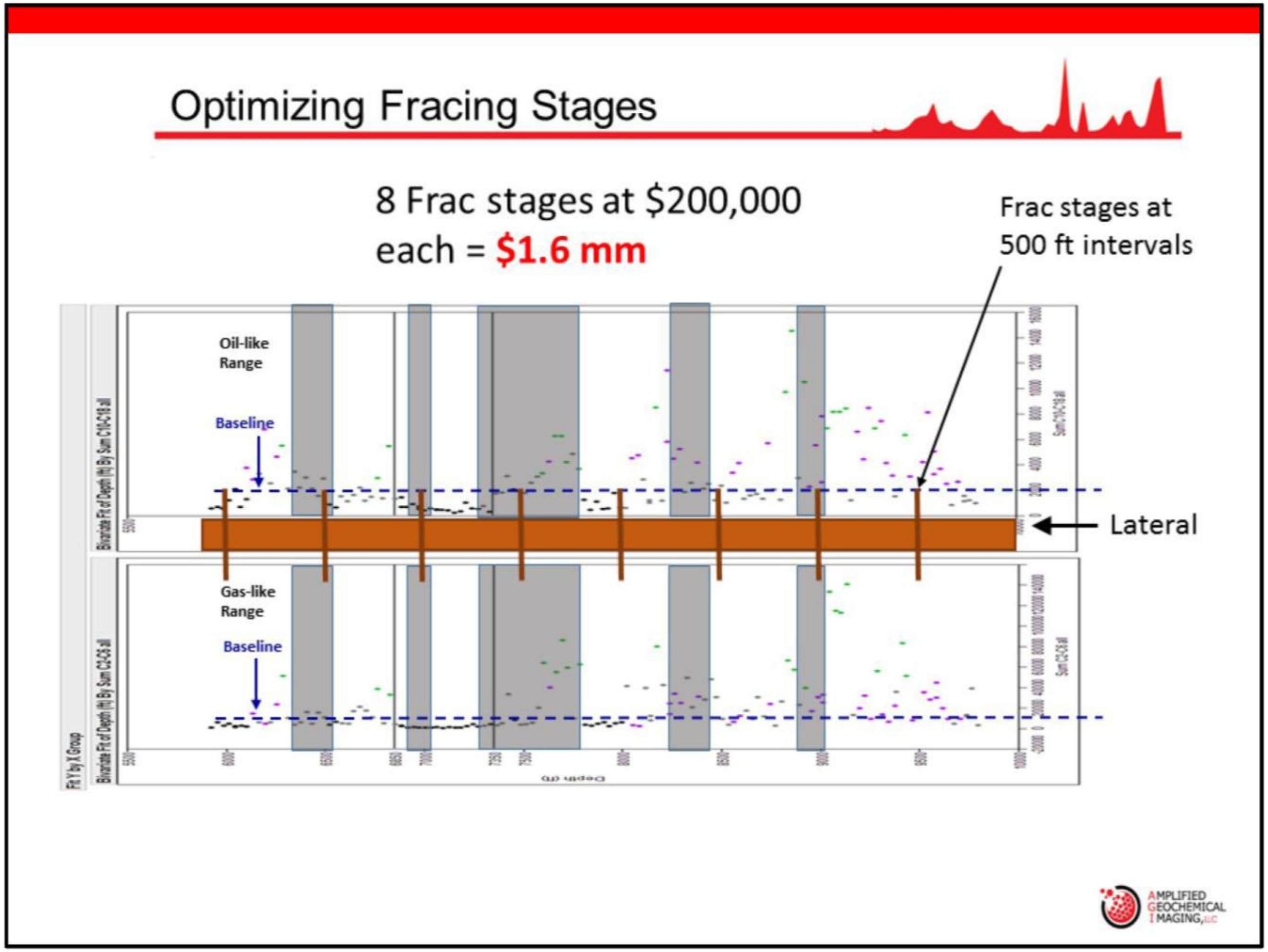
seen between 6,150'-6,200' in the middle of the lower zone. It was believed the HC kick at 6,820' coincided with a small naturally occurring fracture. At 7,650' and 8,250' the drill in the upper zone, which was known to have better porosity and resistivity. At 8,800'-9,230' they reach the top zone which typically has the most fracturing and highest resistivity. The red shading shows that these two sections, 8,250' and 8,800' are by far the most prolific HC bearing zones in the lateral well and stand-out in terms of HC concentration. In addition, the final section between 9,230'-9,400' the lateral went out of the Buda and into the Lower Eagle Ford, which we know from the vertical data, was the second most HC prolific section of the well. It is also very interesting to note that besides the 50' section at 6,150' there are no strong HC responses in the lateral until you get to 7,650'. So, this may indicate, at least in this well, that fracturing before 7,650' may not be economically advantageous.



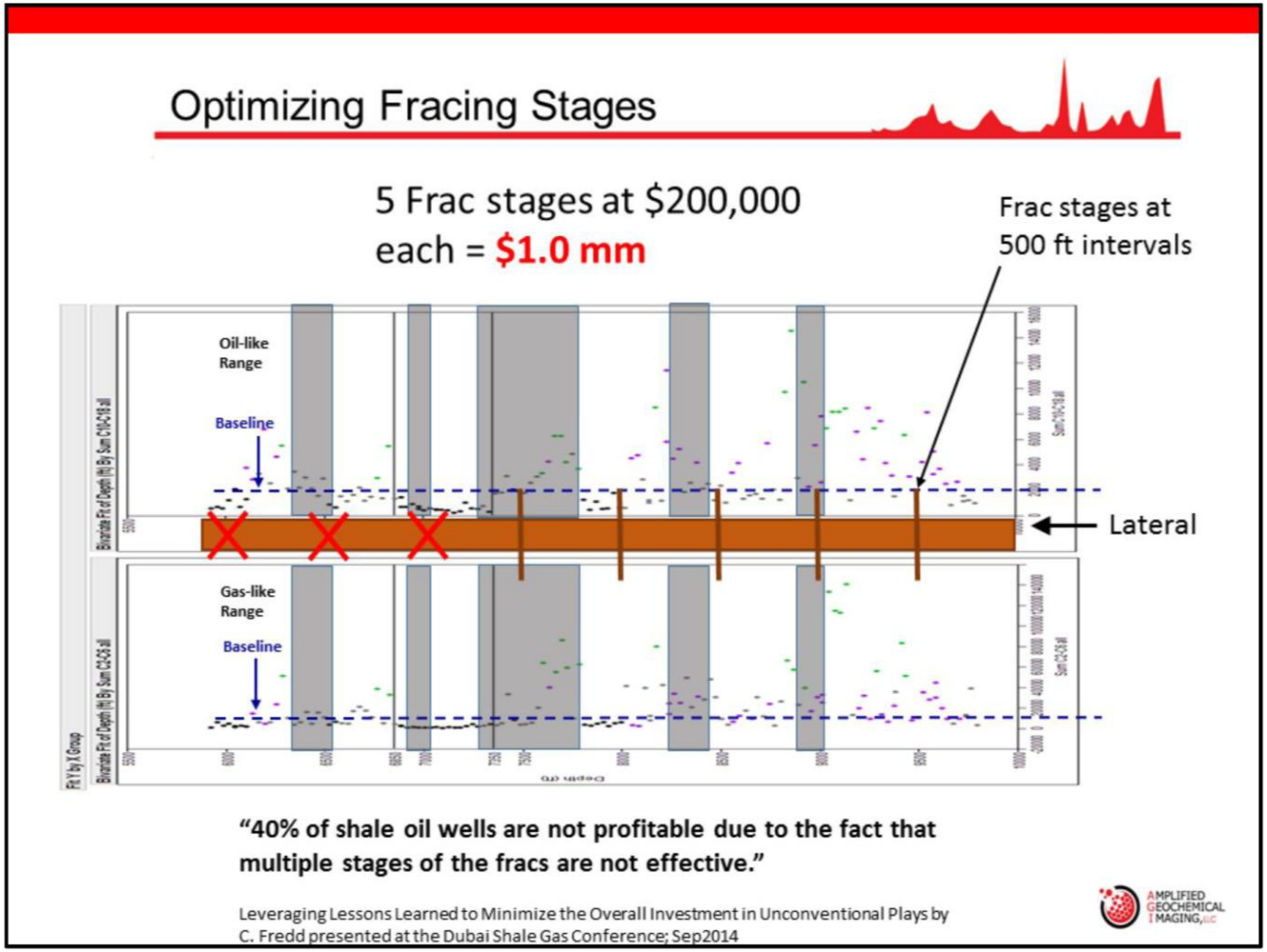
Presenter's notes: This slide shows the approximate location of the lateral well in the Buda Formation. The wide brown section represents the lateral and the brown arrows indicate possible fracturing stages at 500 ft intervals. You can see the hydrocarbon (HC) profile on the left. You can also see that the client attempted to locate the lateral in the sweet spot (i.e. highest porosity and highest HC potential) of the Buda. The blue shaded area represents the possible drainage area (i.e. 500 ft above and below the lateral) of the lateral. You can see that the drainage area encompasses a very poor HC intensity zone, both above and below the lateral. The result is reduced production from this well.



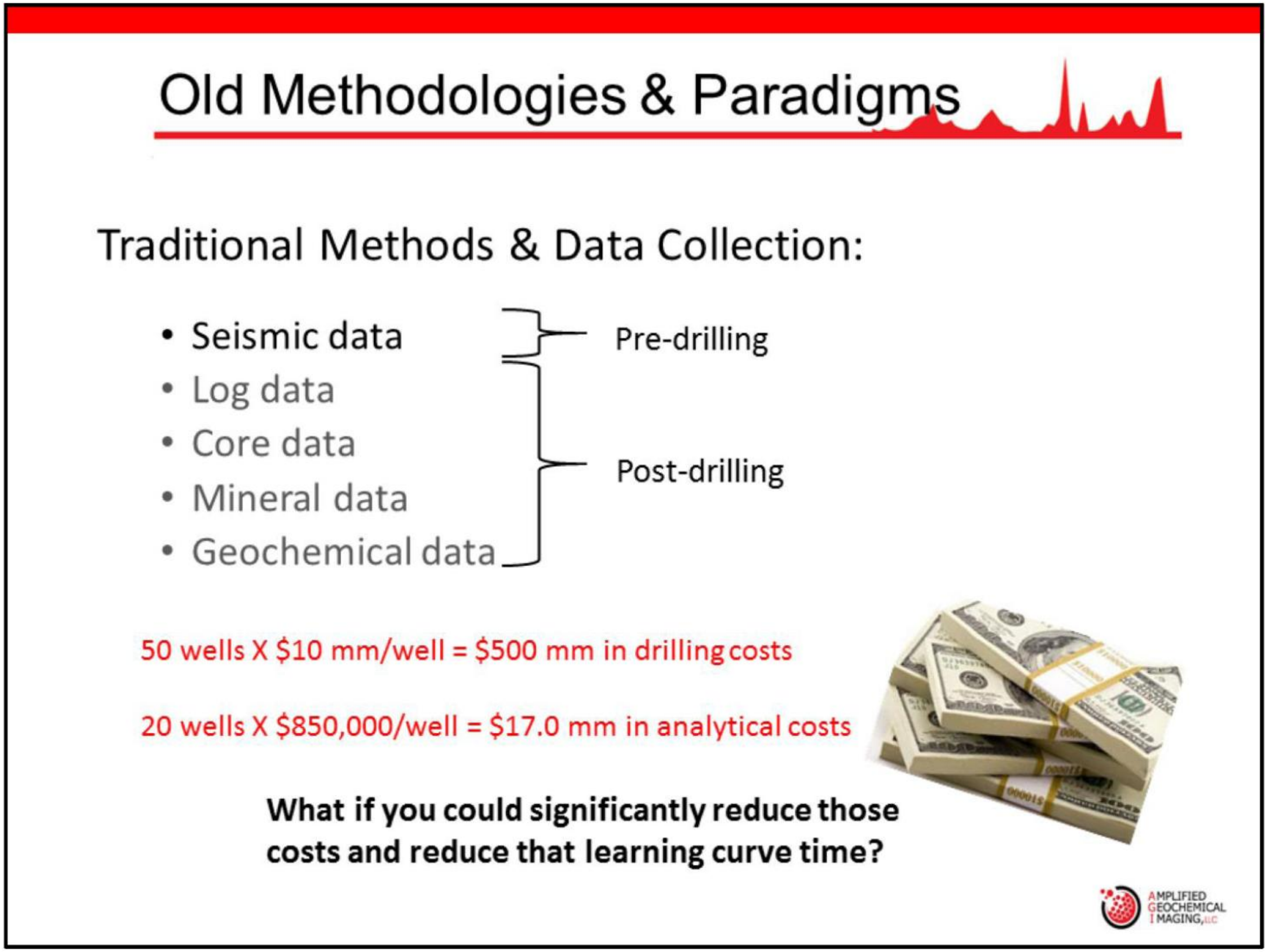
Presenter's notes: This diagram illustrates if the lateral had been placed higher in the well in the Lower Eagle Ford Formation. You can quickly see the drainage area indicated by the blue shaded area incorporates a much more HC rich zone and an area of much higher porosity. Thus, for the same amount of completion investment, the well should gain a substantial increase in production if the DGL vertical data is used to aid in the selection of the lateral placement.



Presenter's notes: Once again, this slide shows the HC intensities in the lateral section. The vertical brown lines represent the possible location of fracturing stages spaced every 500 ft. At a cost of $200,000 per fracture stag, the cost to fracture eight stages in this well would be $1.6 mm. This slide shows what many companies have done over the last few years or continue to do, and that is place their fractures equidistance along the well fracture with the same number of fractures and the same spacing from well to well. However, postmortem field reviews has shown while this may be efficient, it may not be economic.



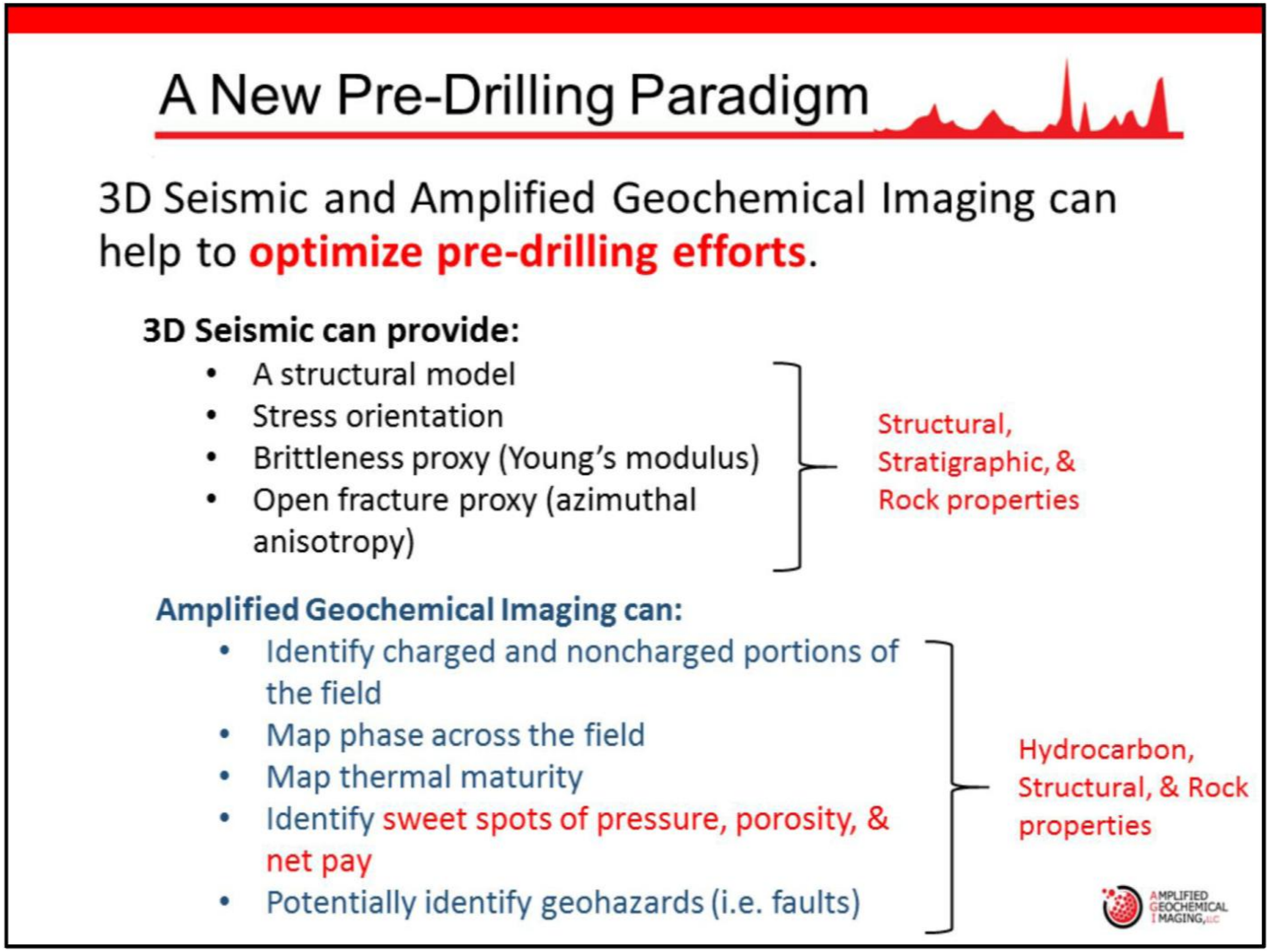
Presenter's notes: A paper given by Chris Fredd recently reported that 40% of all shale oil wells were not profitable because not all stages of the fractures were not effective. There were many reasons for their being non-effective, but the gist of the talk was that we need to optimize our efforts instead of using a template from well to well that may be efficient, but not effective. DGL data shows there are no significant hydrocarbons between 6,000 ft – 7,500 ft. Therefore, why put fracture stages in this area because these fracture stages will add little or no additional production. Thus, you generate the same amount of production from this lateral by skipping the first three fracture stages and save $600,000 in completion costs.



Presenter's notes: Every operator in a shale play goes through a learning curve. Years of production data in North America clearly shows that. The difference between successful and unsuccessful operators are many things, but perhaps one of the most important is their ability to learn quickly and optimize their operations. You cannot optimize operations without metrics and those metrics come from data measurement. The list above shows the most *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

common data sets that are collected. The problem with this data set is that the majority of these data sets (i.e. log data, core data, mineral data, and traditional geochemical data) can only be acquired post-drilling. It was said in the recent Middle East Shale Gas workshop in Sept 2014 that it is safe to assume it would require 50 wells to create an effective data set to evaluate all these measures properties. At $10 mm per well that comes to an investment of $500,000,000 (i.e. half a billion dollars) in well costs to gain the knowledge necessary to optimize your field. It was also mentioned in this conference that it would cost on average (excluding seismic data) $850,000 per well to get all that information. If you did this testing on just 20 wells that would amount to $17 mm in analytical costs. What if you could dramatically reduce that?



Presenter's notes: 3D seismic can add a great deal of information in terms of structural information, stress orientation, brittleness, and identifying possible open fractures. All of these are structural and rock properties that are critical to understanding the shale play. Additionally, AGI data can give information about what hydrocarbons are where. No other technology can to that. They all guess and use proxies to guess. The most important thing is all of these other technologies *(Presenter's notes continued on next slide)*

(Presenter's notes continued from previous slide)

measure a few points, maybe 25 or 50, and then erroneously extrapolate that across the field. AGI actually measures the hydrocarbons across the field and then maps them by phase. No guessing or extrapolating. Additionally, you have seen how AGI surveys can also be a proxy for the pressure, porosity, and net pay combination. And what is great about that is that it is not a specific number but is automatically calibrated to each field and provides red anomalies over the Sweet Spots. In addition, the most important point is this information is PRE-DRILL. All of this critical information can be used to optimize your drilling program and minimize your learning curve. You have seen the math. It can save you millions of dollars in noneconomic and/or low producing wells.

Surface Hydrocarbon Mapping

- can identify charged and noncharged portions of the field
- can generate phase maps across the field
- can map thermal maturity
- can Identify sweet spots of pressure, porosity, & net pay
- can potentially identify geohazards (i.e. faults)

AMPLIFIED GEOCHEMICAL IMAGING, LLC

Downhole Geochemical Logging

- is 1,000 times more sensitive than other methods
- Is the only method that measures from C2 – C20
- can be a powerful proxy for porosity
- can guide the placement of laterals
- can guide your fracing stages

Thank You!

AMPLIFIED GEOCHEMICAL IMAGING, LLC